5 Prevention of an SCC Problem

5.1 Scope Statement

"Compile a report summarizing the history of SCC on pipelines, explaining the causes and factors contributing to SCC initiation and growth, and discussing methods for prevention, detection and mitigation of SCC on pipelines, including effectiveness of ILI tools and other in-the-bell hole examination methods to detect SCC."

The scope statement was broken down into components of Understanding Stress Corrosion Cracking (SCC) in Pipelines (Chapter 4); Prevention of an SCC Problem (Chapter 5); Detection of SCC (Chapter 6); and Mitigation of SCC (Chapter 7).

This chapter summarizes the current state of knowledge for understanding how to prevent SCC, or perhaps more directly, how to prevent an SCC problem in pipelines.

5.2 Coatings

Inadequate coating performance is a major contributing factor for increased SCC susceptibility of an underground pipeline. The majority of high-pH SCC failures have been associated with bituminous coatings (coal tar or asphalt), while the near neutral-pH SCC failures have occurred most frequently on tape-coated pipelines. The surface preparation conditions, degradation modes, and electrical behavior of these coatings are responsible for the type and prevalence of SCC on pipelines. The effectiveness of a coating system in preventing SCC is related to three factors:

1. the resistance of a coating to disbondment,
2. the ability to pass CP current should the coating fail, and
3. the type of surface preparation used with the coating.

Requirements for SCC-resistant coatings can be established, based on these factors, as described below.

In the early 1990s, Pipeline Research Committee International (PRCI) funded a three-year research program to investigate the role of these three factors on resistance to high-pH SCC of common pipeline coatings (Beavers 1992; Beavers, et. al 1993a, 1993b). The ability of a coating to resist disbonding is a primary performance property of coatings and affects all forms of external pipeline corrosion. An intact coating that prevents contact of electrolyte with the steel surface will mitigate all integrity threats associated with external corrosion, including SCC. Coatings with good adhesion properties are generally resistant to the mechanical action of soils from wet/dry cycles and freeze/thaw cycles. They also are better able to resist the effects of water transmission and cathodic disbondment (CEPA 1997).

The ability of a coating to pass CP current, should it fail, is the inverse of shielding the CP current beneath a disbonded coating. Shielding is of special significance to the occurrence of both forms of SCC. Near neutral-pH SCC is more frequently found with coatings that shield CP current, such as tape coatings. In the case of high-pH SCC, the potential range for SCC lies between the native potential of steel in most soils and adequate CP of -850 mV copper sulfate electrode (CSE) (Berry 1974). Partial shielding by disbonded coatings can cause the pipe to lie in the potential range for cracking, even for pipelines apparently protected by CP.

In the PRCI program on coatings, coating impedance tests were performed to evaluate the ability of the different coatings to conduct CP current in the absence of actual holidays (Beavers 1992). Single-layer FBE coatings were found to conduct CP current in the absence of holidays, whereas polyethylene tape coating completely shielded the CP. Coaltar enamel coating exhibited intermediate behavior, allowing CP current to flow after long exposure periods (greater than one year). In the case of the FBE coating, conduction of the CP current was associated with the formation of coating blisters containing a high-pH (greater than 12) electrolyte. This pH is higher than the pH range for high-pH cracking such that this form of cracking is unlikely to occur even if the potential range were appropriate for cracking. Liquid urethanes and epoxies were not tested in the study, but similar behavior would be expected with these and other coatings that are water-permeable.

The relationship between surface condition of a linepipe steel and SCC has been the subject of several previous PRCI laboratory research programs (Barlo and Fessler 1981; Beavers 1992; Beavers et. al 1993a). The research indicates that grit-blasted surfaces are generally more resistant to high-pH SCC initiation than mill-scaled surfaces, primarily because grit blasting imparts a compressive residual stress in the pipe surface. The majority of single-layer FBE coatings are applied in coating mills over grit-blasted surfaces prepared to a white (NACE No. 1/SSPC-SP 5) or near-white (NACE No. 2/SSPC-SP 10) surface finish. The older bituminous coatings were frequently applied over the ditch on mill-scaled surfaces. More recently, bituminous coatings have been applied in the mill using a commercial blast cleaning (NACE No. 3/SSPC-SP 6). The surface preparation necessary for FBE coating was found to be highly resistant to high-pH SCC, in comparison with mill-scaled surfaces. On the other hand, the lower quality grit blast that is commonly used with plant-applied bituminous coatings actually decreased SCC resistance compared to that found with a mill-scaled surface, primarily by creating stress raisers at imbedded mill scale particles. Clean grit-blasted surfaces are also readily polarized in the presence of CP such that the potential is not likely to remain in the cracking range for long periods of time. While the above research was performed on initiation of high-pH SCC, it is possible that the beneficial effects of grit blasting extend to near neutral-pH SCC initiation as well.

In summary, field experience and related research demonstrate that prudent coating selection and proper application are effective tools to prevent SCC of underground pipelines. The CEPA member companies have recommended that the following coatings be consider for new construction based on SCC performance (CEPA 1997):

- Fusion Bonded Epoxy (FBE)
- Liquid Epoxy
- Urethane
- Extruded Polyethylene

- Multi-Layer or Composite Coatings

FBE, liquid epoxies, and urethane coatings meet all three requirements of an effective coating; they have high adhesive strength and are resistant to disbondment, they conduct CP current should they fail, and they are typically applied over a white or near white grit-blasted surface. Extruded polyethylene coatings meet the first and third requirements, but will shield CP current should damage occur. Furthermore, the type of coating used on the field joints frequently limits the performance of extruded polyethylene coated pipelines. Multilayer or composite coatings typically consist of an FBE inner layer and a polyolefin outer layer with an adhesive between the two layers. These new coatings are promising from the standpoint of resistance to disbondment, mechanical damage, and soil stresses, but the polyolefin outer layer will shield CP current should disbondment occur. Additional field experience is needed to establish the performance of these coatings.

Tape coatings and bituminous coatings have been shown to be more susceptible to SCC than the above coatings and should be used only with careful consideration of all of the factors affecting SCC susceptibility.

Regardless of the coating selected, the pipe surface should be prepared to a white (NACE No. 1/SSPC-SP 5) or near white (NACE No. 2/SSPC-SP 10) finish to impart sufficient residual compressive stresses to prevent SCC initiation. A lower quality commercial blast (NACE No. 3/SSPC-SP 6) should not be used under any circumstances.

5.3 Pipe Steel Selection

Field studies of high-pH SCC have not identified any unique characteristics of failed pipe (Wenk 1974). At the time of the study, most of the failures occurred in API 5L X-52 (ASTM Grade 358) line pipe steel, but this was the most common grade for larger diameter line pipe. The chemical compositions of the failed pipes were typical for the vintage and grade, and there were no obvious unique metallurgical characteristics associated with the failures. Similarly, in laboratory studies, no correlation has been found between the concentration of impurities in the steel, such as phosphorus and sulfur, and high-pH SCC susceptibility (Beavers and Parkins 1986). It has been shown that major alloy additions, such as chromium, nickel, molybdenum, and titanium, to steel in amounts of between 2 to 6 percent decrease SCC susceptibility (Parkins et. al 1981) but such additions are impractical because of cost considerations. Resistance to high-pH SCC increases with increasing carbon content (Parkins et. al 1981), but high-carbon steels are difficult to weld.

Data from pipeline failures caused by near neutral-pH SCC showed that this form of SCC has developed on a wide variety of pipe. Pipe failures have occurred on grades varied from API 5L X35 (ASTM Grade 241) to API 5L X65 (ASTM Grade 448) (NEB 1996). Both ERW and double submerged arc weld (DSAW) pipe have been involved in SCC-related failures. The CEPA funded a research program to determine whether the initiation of near neutral-pH SCC could be correlated with pipe metallurgical factors (Beavers et. al 2000). Fourteen pipe samples from susceptible pipe joints, ranging in diameter from 8 to 42 inches (200 to 1,067 mm) and API 5L X-52 to X-70 (ASTM Grades 358 to 483), were examined. The results of this study indicate a strong correlation between residual stress and the presence of near neutral-pH SCC colonies. No statistically significant correlation was found between the occurrence of SCC on the pipes and the other factors evaluated in the study: chemical composition, cyclic stress-strain behavior, inclusion properties (number, area, and composition), and local galvanic behavior. Surkov et al (Surkov, 1994) observed a relationship between susceptibility to near neutral-pH SCC and the length of nonmetallic inclusions in the steel.

One gas transmission company developed an SCC prediction model via a statistical analysis of an extensive database containing information on the construction and operation of the pipeline (Beavers and Harper 2004). Three parameters were found to be key predictive variables in the model; pipe manufacturer, coating type, and soil type. Fourteen pipe manufacturers were used in the construction of the pipeline, and the relative probability of finding near neutral-pH SCC varied by more than a factor of 20 depending on the pipe manufacturer. While the cause of this large difference was not established, it is possible that residual stresses introduced by pipe manufacture played a role, given the other available field and laboratory data.

There is a growing body of evidence to suggest that tensile residual stresses in the pipe play a significant role in SCC and that cracking can be minimized or prevented by reducing these stresses during manufacturing, as well as during installation and operation. The laboratory and field data do not provide any clear guidance with respect to chemistry or other aspects of the pipe manufacturing process and prevention of SCC. The trend in steel manufacturing is to improve the mechanical properties by micro alloying and controlled rolling, and by decreasing the carbon content. Limited research results suggest that these newer steels may not necessarily have greater susceptibility to high-pH SCC even though they have higher yield strengths and lower carbon contents. These results indicate that a more important variable for assessing initiation of SCC is the ratio of the applied stress to the actual yield strength (Parkins et. al 1981).

Higher strength steels may be more susceptible to near neutral-pH SCC given the possible role of hydrogen embrittlement in the cracking process. It is known that if a higher strength pipe is substituted for a lower strength pipe with the same diameter and operating pressure, the critical flaw tolerance of the pipe decreases due to the reduced wall thickness.

5.4 Design Operating Pressure

The predominant longitudinal orientation of both forms of SCC on underground pipelines demonstrates the importance of the hoop stress produced by the internal pressurization on the cracking process. Laboratory studies of initiation of high-pH SCC have shown that stress corrosion cracks initiate above an applied stress level referred to as the threshold stress (Barlo 1979), reported as a percent of the yield stress. This threshold stress is affected by the surface condition, the potency of the environment and cyclic stresses.

In the NEB inquiry (NEB 1996), significant SCC was not reported by Canadian pipeline operators in Class 2 and 3 pipeline locations. CEPA suggested that the standard wall pipe used in Class 2 and 3 locations is less susceptible to SCC because it operates at lower stress levels than pipe in Class 1 locations. The majority of SCC failures on Canadian pipelines have been the near neutral-pH form of cracking. In Class 1 locations, the extent and severity of SCC was found to decrease with decreasing stress, due to the internal operating pressure. On TCPL Line 2, the number of SCC colonies decreased from 0.014 to 0.0005/m (3.56×10^{-4}/in. to 1.27×10^{-5}/in.) inspected as the stress dropped from 75 to 67 percent SMYS. A similar trend was found for crack depth.

Based on laboratory and field data, it is reasonable to conclude that reducing the design operating stress as a percentage of the yield stress can reduce the likelihood of initiation of stress corrosion cracks. Reducing the operating stress has the added advantages of increasing the critical flaw size, as well as increasing the critical leak/rupture length.

5.5 Design Operating Temperature

Fessler evaluated the effect of temperature on high-pH SCC (Fessler 1979). Field data available at the time along with laboratory research on the subject were summarized. Service failures were reported at temperatures as low as 13°C (55°F), but 90 percent of the service and hydrostatic test failures occurred within 16 km (10 miles) downstream from the compressor stations, where the highest temperatures were present. This behavior is associated with a decrease in the width of the potential range for cracking, coupled with a decrease in the maximum cracking velocity with decreasing temperature.

Laboratory data and field experience indicate that there is less temperature dependence for near neutral-pH SCC than for high-pH SCC. Delanty and O'Beirne (1991) reported that 50 percent of near neutral-pH SCC failures on TCPL Line 2 occurred within 10 miles downstream of compressor stations versus 90 percent for high-pH SCC. Because the spacing between compressor stations is typically 100 km (62 miles) on the TCPL System, 16 km (10 miles) correspond to less than about 15 percent of the total length. This behavior suggests that temperature or some other factor affects the occurrence of near neutral-pH SCC, just not to the extent that that it occurs with high-pH SCC. The higher temperature promotes more extensive and rapid coating disbondment, for example. It is also possible that the higher stresses or larger stress fluctuations near the compressor station produce more frequent near neutral-pH SCC failures.

Based on laboratory and field data, it is reasonable to conclude that reducing the design temperature of a pipeline can reduce the likelihood of stress corrosion crack initiation by several processes, including reduced crack velocities, reduced probability of crack initiation (high-pH SCC) and improved coating performance. One method of temperature control that has been implemented by some operators is the installation of cooling towers.

5.6 Construction

Proper construction practices, such as minimizing fit-up stresses and avoiding dents and mechanical damage to the pipe, can reduce the likelihood of SCC initiation. The surface preparation and field-applied coatings for girth welds should be selected and applied with the same care as used in the shop-applied coating. Damage to the coating should be avoided and repaired when it does occur, to avoid holidays, which can act as initiation sites for disbondment.

5.7 Operations and Maintenance

5.7.1 Cathodic Protection

Cathodic protection (CP) is closely related to the high-pH cracking process. The CP current collecting on the pipe surface at disbondments, in conjunction with dissolved CO_2 in the groundwater, generates the high-pH SCC environment. CP can also place the pipe-to-soil potential in the potential range for cracking. The potential range for cracking generally lies between the native potential of underground pipelines and the potential associated with adequate protection (-850 mV CSE) (Parkins 1974; Fessler 1979). Based on field pH measurements of electrolytes associated with near neutral-pH SCC colonies, it has been concluded that this form of SCC occurs in the absence of significant CP either because of the presence of a shielding coating or high-resistivity soils that limit CP current to the pipe surface (Delanty, 1991).

Based on the available laboratory and field data, it can be concluded that the polarized pipe-to-soil potential of pipeline segments that are potentially susceptible to high-pH SCC should be maintained above (more negative than) –850 mV CCS. Potentially susceptible segments can be assessed using ASME B31.8S Appendix A3 for gas pipelines, which considers historical information, coating type, operating temperature, age, operating stress, and distance downstream from the compressor station. For liquid pipelines, the distance downstream of the pump station can be used in the ASME assessment (NACE 2004). The other CP criteria (100mV polarization or 850 mV with CP applied) should not be used on potentially susceptible segments. Consideration should be given to seasonal fluctuations in the potential to minimize the likelihood that the pipe falls into the cracking range on a seasonal basis.

Near neutral-pH SCC is most prevalent on pipelines with shielding coatings (e.g. tape) and has occurred where the pipeline is apparently protected based on CP information. Nevertheless, it is worthwhile to maintain adequate protection to avoid SCC and corrosion at or near holidays. Effective CP also will minimize the occurrence of near neutral-pH SCC with non-shielding coatings.

5.7.2 Recoating Existing Pipelines

The factors that affect SCC performance of a coating system, described above, are applicable to recoating of existing pipelines as well as new construction. These are:

1. the resistance of a coating to adhesion/disbondment,
2. the ability to pass CP current should the coating fail, and
3. the type of surface preparation used with the coating.

As described above, it is imperative that the surface is prepared to a white or near white finish prior to coating application and that the coating applied have desirable performance characteristics, such as good adhesion, resistance to disbondment and the ability to conduct CP current should the coating fail.

There are several other factors that must be considered in the selection of field coatings. These include the ambient weather and environmental conditions required for application, compatibility with existing coatings, equipment requirements, and access to the field site and pipe. Further discussion of these issues is provided in the CEPA SCC Recommended Practice (CEPA 1997).

5.7.3 Other Operational Considerations

Reducing cyclic pressure fluctuations can minimize the occurrence of both forms of SCC. These fluctuations reduce the threshold stress for the initiation of cracks and increase the propagation rate of SCC (Parkins and Greenwell 1977; Beavers and Jaske 1998). Furthermore, final failure of SCC colonies can occur by pressure cycle fatigue for large deep flaws or large pressure cycles.

5.8 References

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